UCRL-ID-129990-95

U.S. Energy Flow–1995

H. Miller
N. Mui
A. Pasternak

December 1997

Lawrence Livermore
National Laboratory

Contents

Abstract

Energy consumption in 1995 increased slightly for the fifth year in a row (from 89 to 91 quadrillion [10^{15}] Btu). U.S. economic activity slowed from the fast-paced recovery of 1994, even with the continued low unemployment rates and low inflation rates. The annual increase in U.S. real GDP dropped to 4.6% from 1994's increase of 5.8%. Energy consumption in all major end-use sectors surpassed the record-breaking highs achieved in 1994, with the largest gains (2.5%) occurring in the residential/commercial sector.

Crude oil imports decreased for the first time this decade. There was also a decline in domestic oil production. Venezuela replaced Saudi Arabia as the principal supplier of imported oil. Imports of natural gas, mainly from Canada, continued to increase. The demand for natural gas reached a level not seen since the peak levels of the early 1970s, and the demand was met by a slight increase in both natural gas production and imports. Electric utilities had the largest percentage increase of natural gas consumption, a climb of 7% above 1994 levels. Although coal production decreased, coal exports continued to make a comeback after 3 years of decline. Coal once again become the primary U.S. energy export.

Title IV of the Clean Air Act Amendments of 1990 (CAAA90) consists of two phases. Phase I (in effect as of January 1, 1995) set emission restrictions on 110 mostly coal-burning plants in the eastern and midwestern United States. Phase II, planned to begin in the year 2000, places additional emission restrictions on about 1,000 electric plants.

As of January 1, 1995, the reformulated gasoline program, also part of the CAAA90, was finally initiated. As a result, this cleaner-burning fuel was made available in areas of the United States that failed to meet the Environmental Protection Agency's (EPA's) ozone standards. In 1995, reformulated gasoline represented around 28% of total gasoline sales in the United States.

The last commercial nuclear power plant under construction in the United States received a low-power operating license in 1995. The Tennessee Valley Authority's (TVA) Watts Bar-1 received a low-power operating license from the U.S. Nuclear Regulatory Commission (NRC). The construction permit was granted in 1972. Also, TVA canceled plans to complete construction of three other nuclear plants.

In 1995, federal and state governments took steps to deregulate and restructure the electric power industry. The Federal Energy Regulatory Commission (FERC) unanimously approved a proposal to require utilities to open their electric transmission system to competition from wholesale electricity suppliers. California has been at the forefront in the

restructuring of the electric utility industry. Plans authorized by the California Public Utility Commission prepare for a free market in electricity to be established by 1998.

In 1990, the U.S. Department of Energy (DOE) began reporting statistics on renewable energy consumption. The types and amounts of renewable energy consumed vary by end-use sector, with electric utilities and the industrial sector being the primary consumers since 1990. Renewable energy provided 6.83 quads (7.6%) of the total energy consumed in the United States in 1995, compared to 7.1% in 1994.

Increasing concern over the emission of greenhouse gases has resulted in exhaustive analysis of U.S. carbon emissions from energy use. Emissions in the early 1990s have already exceeded those projected by the Clinton Administration's Climate Change Action Plan (CCAP) released in 1994 that was developed to stabilize U.S. greenhouse gas emissions by the year 2000.

Introduction

U.S. energy flow charts tracing primary resource supply and end-use consumption have been prepared by members of the energy program and planning groups at the Lawrence Livermore National Laboratory since 1972. These charts are convenient graphical devices to show the relative size of energy sources and end uses because all fuels are compared on a common energy unit basis. The amount of detail on a flow chart can vary substantially, and there is some point where complexity begins to interfere with the main objective of the presentation. The charts in this report have been drawn for clarity and to be consistent with the style used previously.

Energy Flow Charts

Figure 1 is the energy flow chart for calendar year 1995, in quads (one quad equals 10^{15} Btu's). Figure 2 is the same flow chart in exajoules (10^{18} joules). (These figures are printed as the center spread, pages 14 and 15.) The 1995 chart is based on final data published by the Energy Information Administration of the U.S. Department of Energy.[1–4] Conventions and conversion factors used in the construction of the charts are given in the Appendix. For comparison with previous years, consumption of energy resources is given in Table 1. These data in many instances contain revisions of data previously reported in this series.

Comparison of Energy Use with 1994 and Earlier Years

For the fifth consecutive year, U.S. energy consumption registered an increase. The total for 1995 was 90.94 (i.e., 91) quads, up approximately 2% (Table 1). The national economy continued to improve, but the advance was sluggish (Table 2). Inflation fell to under 2% compared to 2.1% in 1994, and the unemployment rate wavered slightly, averaging 5.6% for 1995. California made progress to recover from the recession with the state's unemployment rate dropping from 8.2% in January to 7.7% in December 1995, as shown by the emergence of 300,000 new jobs.[5]

Two of the principal end-use sectors, residential/commercial and transportation, increased their energy consumption by 2.6% and 1.7%, respectively, exclusive of electrical losses (Table 1). The 1.5% increase in energy consumption by the industrial end-use sector was mainly due to an increase in natural gas consumption. The amount of electricity transmitted by the utilities went up by approximately 0.9%, the smallest increase of this decade.

Table 1. Comparison of annual energy production and consumption in the United States.

	Quads (10^{15} Btu)							
	1988	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**
Natural gas production	17.60	17.85	18.36	18.23	18.38	18.58	19.27	19.10
Net imports	1.30	1.39	1.55	1.80	2.16	2.40	2.68	2.90
Natural gas consumption	18.55	19.38	19.30	19.61	20.13	20.83	21.29	22.16
Crude oil and NGL								
Domestic production	19.54	18.28	17.74	18.01	17.58	16.90	16.49	16.33
Imports (incl. SPR)	15.75	17.17	17.12	16.34	16.96	18.51	19.25	18.86
Exports (crude oil)	1.74	1.84	1.82	2.13	2.01	2.12	1.99	1.99
SPR (storage reserve)[a]	0.11	0.12	0.04	-0.10	0.03	0.07	0.03	0.00
Net consumption[b]	34.22	34.21	33.55	32.85	33.53	33.84	34.73	34.66
Coal production (incl. exports)	20.74	21.35	22.46	21.59	21.59	20.22	22.07	21.98
Coal consumption	18.85	18.92	19.10	18.77	19.21	19.83	20.02	20.09
Total fossil fuel consumption	**71.66**	**72.55**	**71.96**	**71.23**	**72.89**	**74.51**	**76.06**	**76.94**
Renewable consumption[c]	2.90	3.10	6.17	6.27	6.11	6.40	6.30	6.83
Electricity								
[Utility consumption for electricity generation]								
Fossil fuels (gross)	20.12	20.54	20.32	20.06	19.99	20.58	20.92	20.92
Natural gas	2.71	2.87	2.88	2.86	2.83	2.74	3.05	3.28
Coal	15.85	15.99	16.19	16.03	16.21	16.79	16.90	16.99
Oil	1.56	1.69	1.25	1.18	0.95	1.05	0.97	0.66
Renewables[d]				3.09	2.70	2.95	2.71	3.16
Conventional hydro				2.90	2.51	2.77	2.54	3.04
Biofuels and other[e]				0.19	0.19	0.18	0.17	0.12
Net electricity imports				0.21	0.26	0.27	0.31	0.28
Nuclear (gross)	5.66	5.68	6.16	6.58	6.61	6.52	6.84	7.18
Transmitted elect. (total)	**9.56**	**9.61**	**9.60**	**9.87**	**10.13**	**10.53**	**10.90**	**11.00**
End-use consumption								
Residential & commercial[f]	16.00	16.26	16.21	16.66	16.79	17.39	17.41	17.87
Industrial[g]	22.09	22.27	25.02	24.74	25.82	26.16	26.91	27.30
Transportation	22.27	22.56	22.54	22.12	22.46	22.88	23.57	23.96
Total consumption[h] (DOE-EIA/LLNL)	**80/80**	**81/81**	**84/81**	**84/81**	**86/82**	**87/84**	**89/86**	**91/91**

Source: *Annual Energy Review*, U.S. Department of Energy, DOE/EIA-0384(96) (July 1997) Table 2.1; *Renewable Energy Annual*, DOE/EIA-0603(96) (Mar. 1997) Tables 1–4; *Annual Energy Outlook*, DOE/EIA-0383(97) (Dec. 1996) Table B.8.

[a]The strategic petroleum reserve storage began in October 1977. A value of 0.0 = less than +500 barrels/day and greater than –500 barrels/day.

[b]Excludes exports but takes into account refinery gains, SPR additions, and other stock changes as well as unaccounted crude oil. Note that this total is not the sum of the entries above.

[c]Includes conventional hydroelectric; net imports of hydroelectric from Mexico and Canada and geothermal from Mexico; biomass, solar (thermal and voltaic), and wind. This energy is used by all the end-use sectors and by the industrial and electric utility sectors for electricity generation. There is a discontinuity in this time series between 1989 and 1990 because of expanded coverage of nonutility use of renewable energy beginning in 1990.

[d]Includes generation of electricity by cogenerators, independent power producers, and small power producers. Excludes imports.

[e]Biofuels include wood, wood waste, peat, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste. Also included are geothermal, solar, and wind. Solar and wind contribute less than 0.5 trillion Btu (1991–1995).

[f]Excludes electrical losses.

[g]Includes field use of natural gas and nonfuel category and excludes electrical losses. Value for industrial consumption shown on Fig. 1 and 2 excludes field use of natural gas and nonfuel use of petroleum as well as electrical losses.

[h]Note that this is not the sum of the entries above. Also, total consumption is presented using numbers reported previously in this series and the number reported by DOE/EIA. From 1990–1994, reports in this series underestimated energy produced from biofuels (approx. 3 quads in 1995), thus affecting consumption quantities.

Table 2. Gross domestic product by major type of product (billions of chained 1992 dollars)[a]

	1994	1995
Gross domestic product	6936	7,254
Goods	2524	2699
Services	3747	3927
Structures	595	628

Source: *Statistical Abstract of the United States 1997: The National Data Book,* U.S. Department of Commerce, 117th ed. (Oct. 1997) Table 694.
[a]"Chained dollars" are a measure of output and prices calculated as the average of changes based on weights for the current and preceding years. Components of real output are weighted by price, and components of prices are weighted by output. These annual changes are "chained" (multiplied) together to form a time series that allows for the effects of changes in relative prices and changes in the composition of output over time.

The total domestic production of the three fossil fuels decreased slightly in 1995, whereas consumption increased. Consumption of coal and natural gas increased slightly, while consumption of oil decreased.

Supply and Demand of Fossil Fuels

Oil Supply

Domestic Production

Oil production in the United States decreased for the fourth year in a row (Figure 3 and Table 1.) Crude oil production fell 1.5% in 1995, while natural gas liquids (NGL) production, comprising only 15% of the total domestic petroleum production, increased by 1.7%.[6] At the beginning of 1995, crude oil reserves fell to 22.46 billion barrels; NGL to 7.17 billion barrels. These are the lowest levels the United States has seen in 41 years.[7]

Of the total U.S. production of crude oil, 79% came from onshore wells and the rest from federal offshore wells. The rate of refinery utilization fell from a high of 93% in 1994 to 92% in 1995. The Alaskan North Slope production continued its decline.[7]

Continued exploration and development in the Gulf of Mexico Federal Offshore area led to an 18% increase in Gulf crude oil reserves. New field discoveries totaled 114 million barrels of reserves, mostly from the deepwater areas of the Gulf of Mexico Federal Offshore region; and the total production of crude oil in the Gulf was 292 million barrels, an increase of 10% from 1994 values.[7]

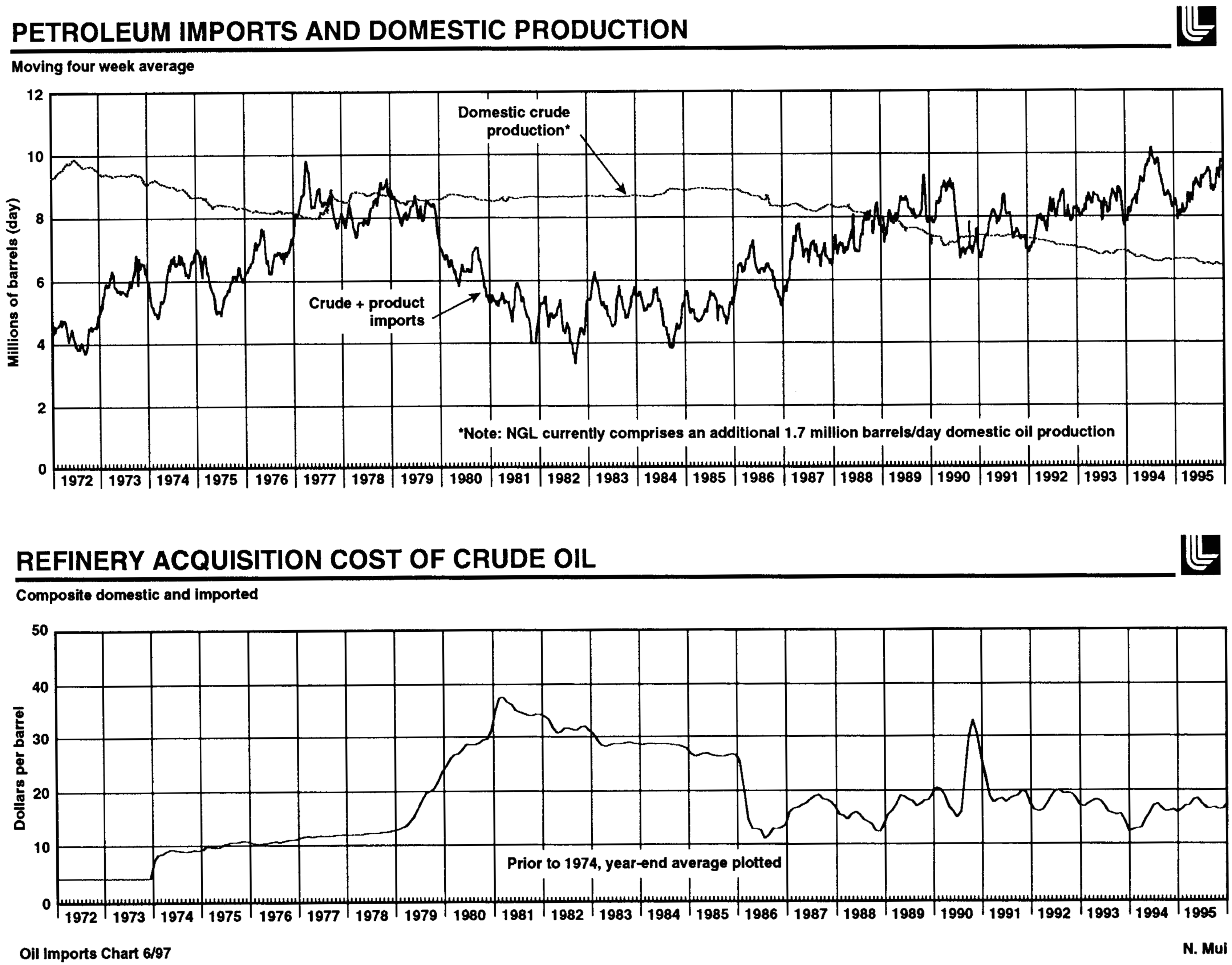


Figure 3. Petroleum imports and domestic production; refiner acquisition cost of crude oil.

Domestic crude oil prices increased from the average 1994 levels in all categories of sales. (Figure 3 shows the refinery acquisition cost of crude oil, a composite of both domestic and imported oil.) A general move towards sustaining lower stock levels of products, increased demands, and unusual weather trends appeared to be the most significant factors affecting product prices in the United States. Following the usual pattern, prices for crude oil peaked in the spring at $20.53 per barrel on May 1, 1995. The average price decreased gradually in the next few months but peaked again by the end of August, driven by reports of low stocks. The year's low of $16.86 per barrel was reached in early October, but prices increased yet again because of low stocks and inclement weather conditions.

In mid-November, Congress entertained bills to permit the leasing of the Arctic National Wildlife Refuge Coastal Plain. The House bill contained a provision to sell the Elk Hills Naval Petroleum Reserve in California, and the Senate version of the bill contained a provision to grant royalty relief to marginally economic oil and gas fields in the deepwater Gulf of Mexico.[8] The Outer Continental Shelf Deep Water Royalty Relief Act was finally enacted on November 28, 1995, giving the Secretary of the Interior authority to suspend royalty requirements on new oil and gas production from qualifying existing leases.[9]

The 23-year ban on exports of crude oil from the Alaskan North Slope (ANS) was finally lifted in 1995. By the end of the year, a law was enacted to repeal the export ban, which opened up about one-quarter of U.S. crude oil production for export. The ANS legislation also waives royalty payments on deepwater oil and gas leases in the Gulf of Mexico. The law gives the President the power to impose new export restrictions in the event of severe oil supply shortages.[10]

Oil Imports

U.S. dependence on petroleum net imports was 44.5% in 1995, down from the 17-year high of 45.5% in 1994.[11] At 7.2 million barrels per day, crude oil imports increased 2.4% since 1994, while petroleum product imports at 1.6 million barrels per day decreased 17%.[12] There were no net changes in the strategic petroleum reserves (SPR) for 1995.

The main suppliers of petroleum to the United States in 1995 (Fig. 4) were Venezuela (1.5 million barrels/day [b/d]) and Saudi Arabia (1.3 million b/d), both members of the Organization of Petroleum Exporting Countries (OPEC), and Canada (1.3 million b/d) and Mexico (1.1 million b/d) of the non-OPEC nations. These four countries collectively supplied almost 60% of total U.S. imports of petroleum products.[13]

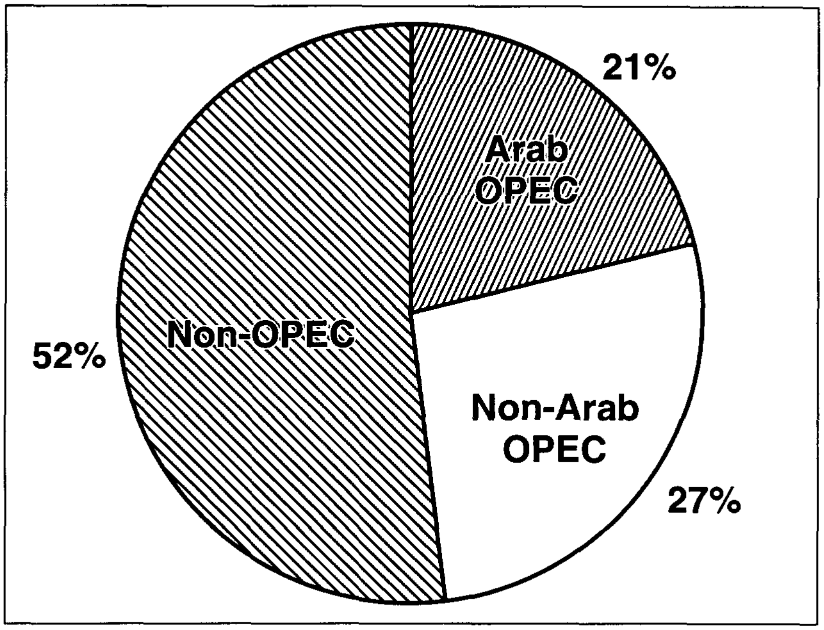


Figure 4. Source of U.S. petroleum imports in 1995.
Source: *Monthly Energy Review*, DOE/EIA-00035(97/12), U.S. Department of Energy, Washington, DC (Dec. 1997) Table 3.3.

Fluctuations in crude oil price were affected by several main factors: reductions in inventory, severe weather conditions in the United States, and increased demands. The "severe" weather conditions can be described as unusually warmer conditions through the 1994–1995 winter season and unusually cold conditions through the winter months at the end of 1995.

The reduction in product stocks occurred mostly in the first half of 1995 while providing supply for end-use consumption. The unanticipated severity of the winter season in late 1995 caused the continuation of large stock withdrawals; and, as a direct result, there was no net input to the petroleum stocks.

Oil Demand

Consumption of petroleum increased because of growth in the transportation sector's energy demand. Sales of distillate fuel oil (No. 1, 2, and 4 fuel oils and No. 1, 2, and 4 diesel fuels) increased by 2.1%, mostly because of increased demand from the transportation sector (diesel fuel, railroad, vessel bunkering), which uses almost 61% of the distillate fuels.[14] Distillate fuels comprise about 32% of total transportation fuel demands.[15] The remaining transportation fuel demands are for motor gasoline and jet fuel, comprising about 65% and 13%, respectively. Residual fuel oil sales fell for the sixth year in a row because of price, availability of alternatives, and environmental regulations. Residual and distillate fuel oil make up 19% and 81%, respectively, of the total distribution of fuel oils.[16]

In the residential and commercial sectors, distillate fuel oil use decreased. The same downward trend was apparent in the industrial sector because of a 4.1% increase in the use of natural gas. The electric utility sector should also see a reduced demand for residual fuel oil when more natural gas and coal plants become operational. One factor that could slow down the drop in residual fuel oil use in the future is the anticipated decommissioning of nuclear power plants.[17]

January 1, 1995, marked the beginning of the federal mandate for the use of reformulated gasoline in areas that exceeded the allowable levels of ozone pollution. Refinery sales of finished motor gasoline rose by 3.9%.[18] Reformulated gasoline accounted for 25.2% of total motor gasoline sales. The average wholesale price of one gallon of all types of motor gasoline rose from 74 cents in 1994 to 77 cents in 1995.[19]

Transportation Demand

In the transportation sector, consumption of oil products continued to rise and so did emissions of greenhouse gases. Between 1980 and 1985, oil consumption for transportation increased by 0.5 quadrillion Btu because of the limited competitive alternatives available for vehicle fuels and despite marked improvements in the fuel efficiencies of light-duty vehicles.[20] Between 1990 and 1995, the increase grew to almost 2 quadrillion Btu. Although the Energy Policy Act of 1992 mandated the production of alternative-fuel vehicles (AFV), stronger legislation such as the implementation of the Low Emission Vehicle Program (LEVP) regulations will not begin until 1998 in New York and until 2003 in California and Massachusetts, at the earliest. The LEVP legislated sales are anticipated to boost electric and electric-hybrid vehicles to about 33% of AFV sales, which should eventually decrease levels of petroleum consumption from transportation demand.[21] The demand for delivery of goods and services increased in 1995 and pushed distillate sales in the transportation sector up 5.3%.

Natural Gas Supply

Domestic dry gas production decreased 12% in 1995 for the first time in four years.[22] A weak demand in the residential and commercial markets together with the expanding level of imports contributed to slowing the rate of production. An exceptionally warm winter caused the initial low demand and in turn created "unusually high" spring inventories.[23] Imports from Canada and withdrawals from storage were used to meet the increased demand.

Canadian imports continued to play a major role in the U.S. natural gas supply (Fig. 5) and reached a record high of 2.8 trillion cubic feet in 1995, representing 13% of the total U.S. natural gas supply.[24]

Deregulation of the natural gas industry in the 1980s allowed consumers to purchase natural gas directly from producers and to arrange fee-based delivery from pipeline and distribution companies.[25] This change in market dynamics has placed pressure on producers to cut costs and improve the efficiency of operations.[26]

The largest production increases for 1995 were partly due to coalbed methane recovery projects in Colorado and New Mexico and to increased transportation capacity to support selling larger volumes. Production declined in the Gulf of Mexico in spite of the development of many large deepwater projects (200 meters or more) in response to a weakened market for domestic gas production.[26]

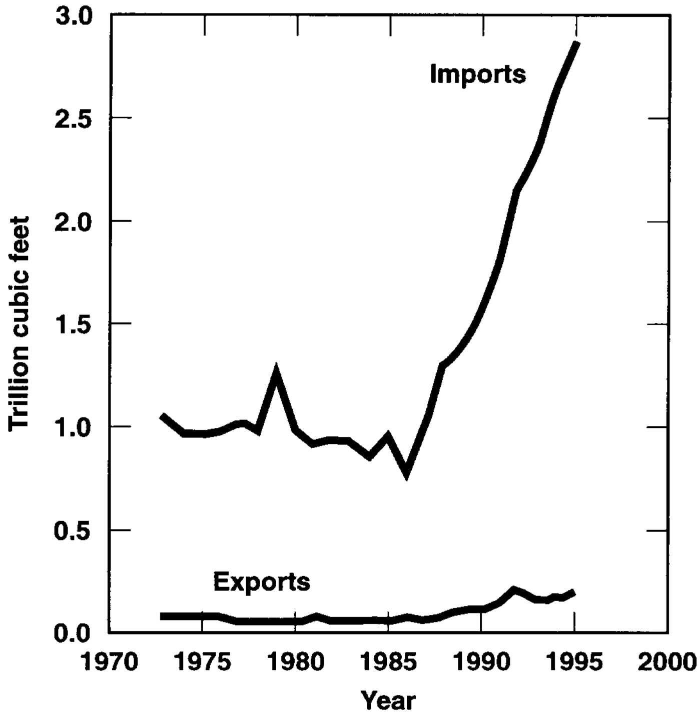


Figure 5. Growth in natural gas imports to the United States
Source: *Annual Energy Review—1996*, DOE/EIA-0384(97), U.S. Department of Energy, Washington, DC (July 1997) Table 6.1; *Monthly Energy Review*, DOE/EIA-0035 (96/07), U.S. Department of Energy, Washington, DC (July 1996) Table 4.3.

The rate of interstate pipeline capacity expansion during 1995 was slower than in previous years, but overall pipeline capacity and deliverability increased. Three new interstate pipelines were placed in service that resulted in a net increase in natural gas transmission of 610 million cubic feet per day. The new pipelines are the Tuscarora pipeline in northern California, the Crossroads pipeline between northern Indiana and western Ohio, and the Bluewater pipeline between Michigan and Ontario, Canada. Several other expansion projects also increased capacity by up to 950 million cubic feet per day.[27]

U.S. proved reserves increased 1% in 1995, up 2,731 billion cubic feet from those in 1994. Improved technologies in exploration and deepwater production technologies improved the ability to discover and develop offshore fields.[28]

Underground storage of "working gas" (that in excess of the base gas needed to maintain optimum reservoir pressure) equaled 2.2 trillion cubic feet at the end of 1995, and the base gas in storage was 4.3 trillion cubic feet.[29] The utilization of "high-deliverability" storage systems in recent years has allowed reserves in underground storage to be used to provide peaking supply or short-term swing supply instead of providing backup supply.[30]

Natural Gas Demand

Approximately 38% of the natural gas consumed in the United States is by industry, including cogenerators and other nonutility electrical generating enterprises (see Fig. 1). In the residential sector, the same amount of natural gas was consumed in 1995 as was consumed in 1994, whereas the use of natural gas in the commercial sector was up 4.5%. In spite of record low temperatures in the eastern United States towards the beginning part of the year, overall winter conditions in the winter season of 1994–1995 were moderate compared with the previous heating season. Because residential and commercial sector consumption is mostly affected by weather-related space-heating requirements, the following effects are noted. Because of generally warmer weather during the heating season months of 1995, consumption by the residential sector was flat. However, the increase of natural gas consumption from the commercial sector for space-heating requirements was due in part to economic growth.[31] The price of natural gas remained fairly low throughout the year; the average price fell almost 7% from 1994 values.[32]

Industrial consumption of natural gas rose almost 6% in 1995. A steady increase in natural gas consumption by industry for the past few years is due in large part to the increasing number of nonutility electricity generators, whose fuel of choice is natural gas. Much of the natural gas consumed by nonutility generators is used for cogeneration. Also, more natural gas was available because of increased pipeline capacities and milder weather, and prices were generally low during the year.[33]

Electric utility use of natural gas increased by only 0.3% (0.01 trillion cubic feet). The long-term outlook for natural gas demand is uncertain because of the restructuring of the electric power industry. In 1996, the Federal Energy Regulatory Commission (FERC) issued Orders 888 and 889 (the restructuring orders) requiring transmission-owning companies to separate power sales from transportation services. These changes are expected to affect both the demand for natural gas for power as well as the organization of the energy-supply industries and how gas competes with electricity for end-use sales.[33] Some electric utilities are already reaping the rewards of low-cost natural gas fuel for electricity generation.

The transportation sector consumption of natural gas increased by only 1.5% in 1995 to 0.7 trillion cubic feet.[34] Transportation consumption includes pipeline fuel, i.e., natural gas consumed in the operation of pipelines (primarily compressors) to which the 0.7 trillion cubic feet is assigned. Less than 5 billion cubic feet per year of natural gas has been consumed as vehicle fuel since 1990.[34]

Coal Supply and Demand

Coal production in the United States totaled over 1 billion short tons in 1995, slightly lower than 1994 levels. Coal production from the west accounted for 42% of total U.S. production. With the decline in coal output of the Appalachian and interior regions, even the large increase in deliveries of low-sulfur, low-ash coal from the Powder River Basin, Wyoming, to the eastern and midwestern coal markets were not enough to compensate for the decline.[35]

Coal consumption increased to almost 1 billion short tons during 1995, a record reflecting increased use of coal for electricity generation, with 86% of the consumption by electric utilities and 2.2% by independent power producers. Most of the remaining coal was consumed for coke-plant use and in other "industry and miscellaneous" uses (includes transportation sector consumption), at 3% and 8% respectively. Residential and commercial consumption was at 5.8 million short tons (0.6%).[36]

Electric nonutilities increased their demand in 1995 to 12 million short tons of coal. Most of the additional coal consumed in the United States was by electric utilities located in the east south central, west north central, and east north central regions. Combined, these three regions accounted for 48% of the total electric utility coal consumption in 1995. Other regions also reported higher coal consumption for coal-fired electricity generators, but those increases were offset by declines in coal consumption in the Pacific and Mountain regions.[37]

Coal exports rose approximately 19% in 1995. Coal exports recovered from their downward trend experienced over recent years but still did not compare to export levels from 1984–1986 and 1988–1989.[38] The majority of exported coal went to European countries, which were unable to receive their usual amounts of steam coal from other major exporters. The average price for U.S. steam coal exports rose to $34.51 per short ton (0.5% increase), and the average price for U.S. metallurgical coal exports rose to $44.30 per short ton (3.6% increase).[39]

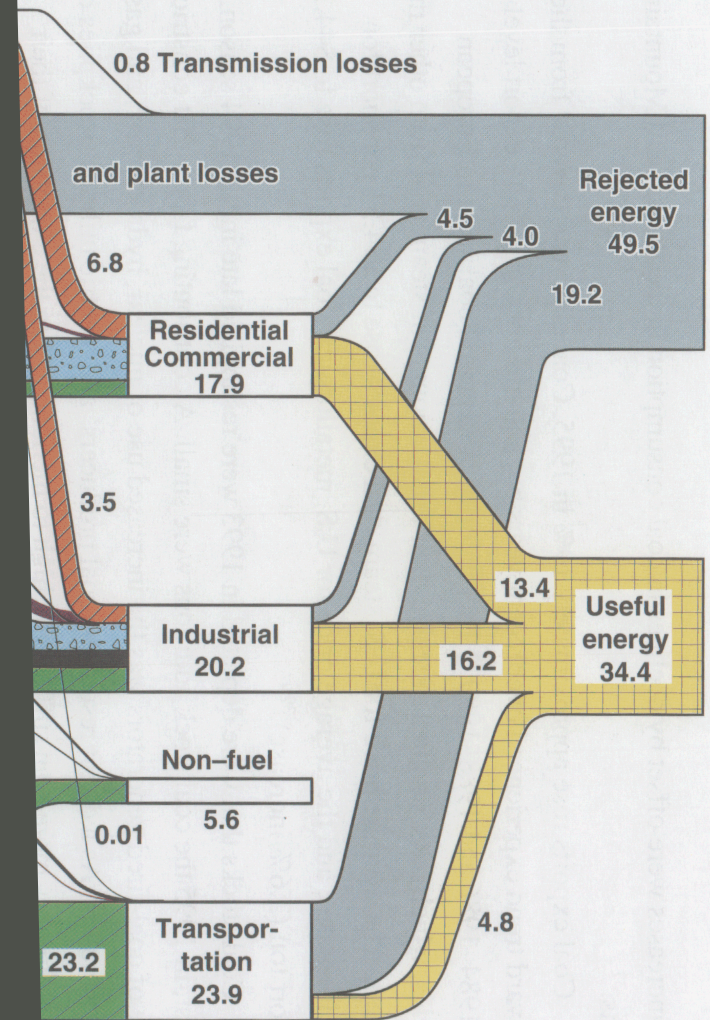
Coal stocks that were depleted in 1993 were resupplied late in the 1994 season. In contrast, in 1995 the coal stock additions were small. A contributing factor that constricted the use of coal-fired generators was the increased use of nuclear, hydroelectric, and gas-fired generators. As a direct result, the coal producers' and electric utilities' stockpiles of coal buildup was more than sufficiently high to merit an end to the expansion of their supplies. However, during the second half of 1995, a rise in utility coal-burns quickly reduced the stockpiles and caused them to return to the levels of the previous year.

Because the coal industry counts on the electric utilities for its business, coal prices are predicted to be forced down as the utilities are deregulated and subjected to price competition for the first time. Even though coal is currently less costly than oil or gas on a Btu basis, the initial cost of production for coal-burning electricity generation is higher than for natural-gas-fired generators. When the projected price drops in electricity occur, coal and other fuels will possibly become lower.

Renewable Energy Consumption

DOE began reporting statistics on consumption of renewables in 1990. Renewable fuels include conventional hydroelectric power, biofuels, geothermal energy, solar energy, and wind energy. In 1995, renewable energy increased its market share of U.S. energy supply by 5.6%, contributing 7.5% of the total energy consumed.[40] At 6.83 quads, renewable energy consumption was up 8.4% from 1994. Since 1991, renewable energy consumption has increased at an annual rate of 2.2% per year. Distribution of renewable energy consumption in 1995 by sector was as follows: electric utility, 50% (3.44 quads); industrial, 38% (2.58 quads); residential and commercial, 10% (0.71 quads); and transportation, 2% (0.11 quads). Sixty-five percent (4.4 quads) of the total renewable energy consumption was used to generate electricity in 1995: industrial sector, 0.99 quads; electric utility sector, 3.16 quads; and net imports of 0.28 quads.[40]

ion 91 Quads



H. Miller
US En. Flo. 95
Final 12/97

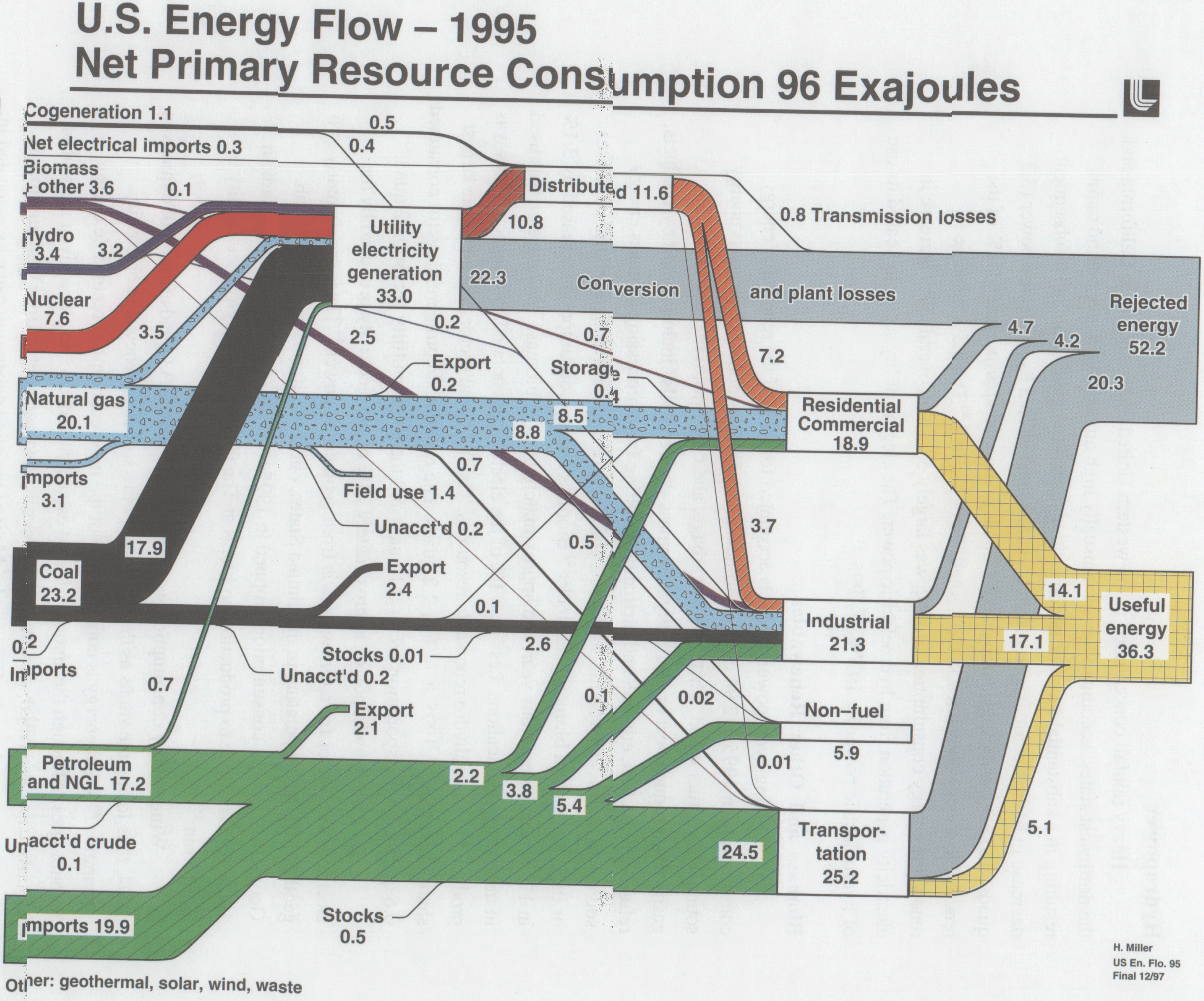


Figure 2. U.S. Energy Flow—1995, in exajoules.

Hydropower

Heavy rainfall concentrated in the western United States, mostly in California and the northwest states, accounted for the unusually high amounts of water behind dams, resulting in a substantial increase in domestic hydroelectric generation and a subsequent decrease in hydroelectric imports from Canada. Conventional hydroelectric power (3.2 quads) and net hydroelectric imports (0.3 quad) comprised approximately 51% of the renewable energy consumed in the United States in 1995.[40] The 8.5% increase in renewable energy consumption in 1995 was largely due to an overall 17% increase in electricity generation from hydroelectric power. The electric utility sector increased its use of hydroelectric power by 19.7% in 1995.[41]

Biomass and Other Renewables

Excluding hydropower, biofuels accounted for 87% of the renewable energy consumption in 1995 at 2.94 quads. Biofuels are defined as nonfossil biomass energy sources (e.g., fuel wood, waste wood, garbage, and crop waste) that are burned or gasified to produce heat or electricity. "Biomass-derived fuels" include wood by-products, refuse-derived fuel, ethanol, and methanol, resulting from processing biomass energy sources. Biomass-derived fuels may be byproducts of industrial or agricultural processes or fuels made from biomass feedstocks.[42] Biomass energy consumption increased by 3.1% in 1995 over the previous year, and approximately 80% of biomass consumption was used in nonelectric applications. Less than 1% of the electricity generated by electric utilities was produced from nonhydro renewable resources. The industrial sector consumed the largest share of biofuels in 1995 at 74% or 2.2 quads. The residential/commercial sector consumed 0.6 quads, the transportation sector 0.1 quad, and the electric utility sector 0.02 quad.[43]

Excluding hydropower, approximately 74% of the electricity produced by the electric utility sector from renewables is from geothermal power.[44] There are currently two geothermal plants operating in the United States, one in California and one in Utah. Geothermal energy consumption dropped in 1995 to 0.325 quads from 0.381 quads in 1994, primarily due to production problems at The Geysers, a utility-owned facility in California.[45]

Wind energy consumption was down in 1995 to 0.033 quads from 0.036 quads in 1994, thus losing the status as the fastest-growing source of renewable electricity generation.[46] Wind energy is currently one of the most economical renewable energy technologies. Although the amount of wind capacity needed to deliver a given amount of effective capacity is high, the amount of electric power generated from wind turbines is expected to grow from the 1995 level.[46] Most of the wind generating capacity is located in

California, but wind farms are currently under construction in Minnesota, Iowa, Hawaii, Texas, Wisconsin, and Washington, with demonstration projects planned in New England and Wyoming.

Solar energy consumption rose by 9% in 1995 after 4 years of virtually no growth. This is mostly a result of nonutility solar-powered generation, because there is virtually no solar electricity generated in the electric utility sector.[45] Grid-connected solar electricity generated 0.8 billion kWh. Even though solar accounts for less than 2% of all renewable electricity generation, new capacity and generation from central receiver and dish Stirling technologies will allow for future growth.[47] U.S. nonutility power producers reported installed capacity of 358 MW from solar in 1994, with gross electricity generation of 824 million kWh from solar thermal collectors.[48] Nine operating Solar Electric Generating System plants in southern California accounted for 98% of the total nonutility solar generating capacity.[49]

Electrical Supply and Demand

Electricity distributed by the public utilities increased by almost 2% in 1995, a continuation of the increases forecast since the beginning of the decade (Fig. 6). Total electric utilities generating capacity in 1995 was 706,112 MW.[50] The United States imported 47 billion kWh of electricity from Canada and Mexico in 1995, a decrease from the previous year.[51]

Coal maintained its role as the primary source for electricity in the United States, generating 54% of the total. Nuclear energy was in second place with 23% of total net electricity generation. Natural gas, hydropower, oil, and geothermal and other sources followed in order of importance. The biggest changes in utility electricity generation came from an increase of nuclear and hydropower sources and a decrease in the amount of oil used.[52]

Gas-fired generation rose to its highest levels since 1981 because of higher petroleum prices, an abundant supply of low-cost natural gas, and higher pipeline capacities. The sulfur content of coal delivered in 1995 decreased as a direct result of the Clean Air Act Amendments of 1990. Starting January 1, 1995, Phase I set emission restrictions on 110 mostly coal-burning plants in the eastern and midwestern United States. Because of this, electric utilities are expected to purchase greater percentages of low-sulfur coal to meet the new emission requirements.[53]

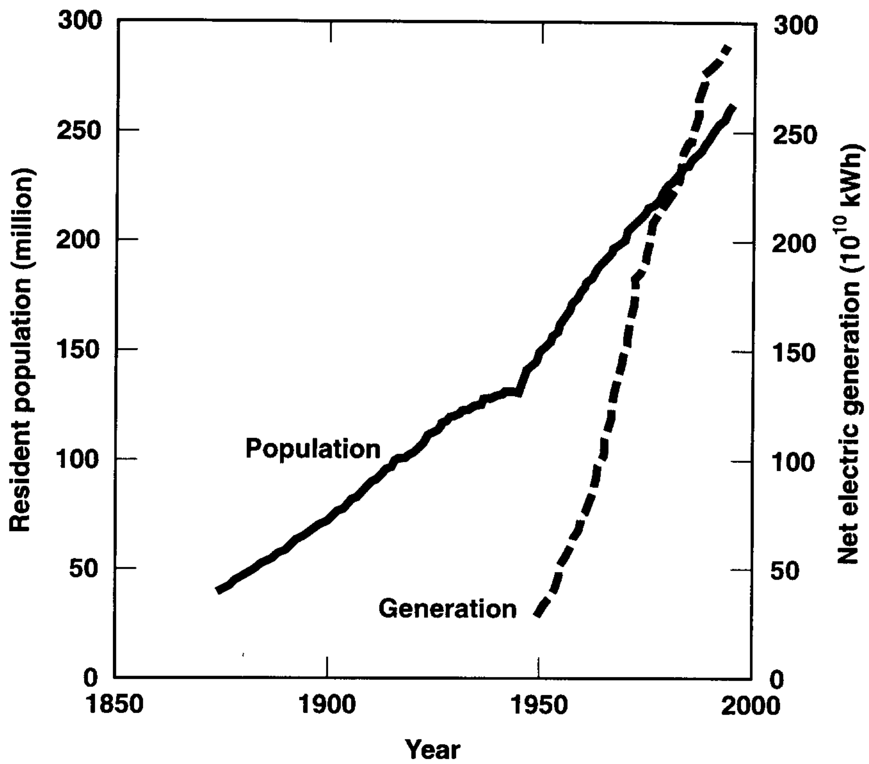


Figure 6. Growth of U.S. population and net utility electrical generation.
Source: *Historical Statistics of the United States—Colonial Times to Present*, U.S. Department of Commerce, Washington, DC (1975) Series A 6-8; *Annual Energy Review—1994*, DOE/EIA-0384(94), U.S. Department of Energy, Washington DC (July 1995) Table 8.3; *Statistical Abstract of the United States—1996*, U.S. Department of Commerce, Washington, DC (1996) Table 2; *Monthly Energy Review*, DOE/EIA-0035(96/10), U.S. Department of Energy, Washington, DC (October 1996) Table 7.1.

The main energy source for the nonutility producers shown in Table 3 was natural gas, which accounted for more than half of electricity generation by nonutilities in 1995. Generation from petroleum and coal each consisted of about 15% of the total. Nonutility capacity additions planned for 1996 through 1998 totaled more than 4 GW, while the electric utilities planned to add 11 GW of new capacity (generator nameplate capacity) during this same period.[54]

The trend appears to be towards gas-fired capacity generators. In 1995, of the 5,752 MW in new units that became functional, 48% are gas-fired generators. No new nuclear units came on-line (although one received a low-power operating license) or were retired in 1995.[55] Electric power producers are looking towards nontraditional methods to increase generating capacity. Rather than concentrating on the building of new additional

Table 3. Installed capacity and gross generation of nonutility electric generators larger than 5 MW and 1 MW for years after 1992.[a]

Year	Installed capacity (GW)	Increase (%)	Gross generation (billion kWh)	Increase (%)
1989	36.6		187.1	
1990	42.6	16.1	215.2	15.0
1991	48.2	13.2	248.5	15.5
1992	56.8	17.8	296.0	19.1
1993	60.8	7.0	325.2	9.9
1994	68.4	12.6	355.0	9.1
1995	70.3	2.6	374.4	5.5

Source: "Statistics on nonutility power producers," reprinted from *Monthly Energy Review* (Aug. 1992 data) (Oct. 1992); *Electric Power Annual—1995*, Vol. 2, DOE/EIA-0348(95)/2, US Department of Energy, Washington, DC (Nov. 1995) Table 1.

[a]Through 1991, only nonutility electric generators larger than 5 MW were included in the data provided in Table 3. Starting in 1992, nonutility electric generators larger than 1 MW have been incorporated into the data.

units, the focus has shifted to "rerating, repowering, or life extension of existing units, purchases from nonutility power producers, and demand-side management (DSM) programs."[56] By reforming the demand and energy uses of the consumers, electric utilities are preparing to reduce electricity consumption. Approximately 47 GW of peakload reductions could be attributed to DSM programs in 1995.[54]

Deregulation and Restructuring of the Electric Power Industry

In 1995, both federal and state governments took steps to continue the process of deregulating and restructuring the electric power industry begun by the Energy Policy Act of 1992. The economic magnitude of the proposed changes is huge: annual electricity sales in the United States are about $200 billion, the investment in utility plants and equipment is about $500 billion, and the upgrading and replacement of capital stock is about $25 billion per year. Demand for electricity is growing faster than demand for other energy sources and faster than growth of the gross domestic product. Deregulation and restructuring are expected to result in the desegregation of vertically integrated utilities, with generation, transmission, and distribution of electric power becoming functions of separate companies.[57]

Competitive forces in the electric utility industry, benefiting large customers, were evident in advance of governmental regulatory action, with utilities offering large industrial customers discounts in exchange for long-term contracts.[58] Mergers of major utilities were another sign of the anticipation of and adjustment to the coming competitive market.[59]

In March 1995, the Federal Energy Regulatory Commission (FERC) approved, by a unanimous 5–0 vote, a sweeping proposal to require utilities to open their electric transmission systems to competition from wholesale electricity suppliers. The proposal would require 137 investor-owned utilities to allow open access to their transmission grids. The objective of the proposed rule was to encourage power sales by the lowest-cost producers by facilitating access to the grid and electricity sales for smaller utilities and independent power producers. Under the proposal, utilities would have to file their transmission costs and prices with the FERC, which is an independent regulatory agency within the U.S. Department of Energy.

The FERC proposal includes a mechanism by which utilities could recover their so-called "stranded costs" for assets that might not be competitive in a non-monopoly market. Utilities would file requests with the commission to recapture costs either by an "exit fee" charged to customers who leave the system or by allowing an extra charge for power transmission.[60]

In California, progress toward deregulation and competition focused on two competing approaches that divided both the California Public Utility Commission and the investor-owned utilities. Southern California Edison Company favored establishment of a wholesale power pool into which electric generators would sell on a competitive basis and from which power would be sold to customers at a uniform rate. Environmentalists, consumer groups, and Pacific Gas & Electric Company favored an open market system allowing for bilateral sales agreements between customers and suppliers. The CPUC had adopted an open market approach in April 1994, but by May 1995 it was clear that this would be significantly modified.[61]

On December 20, 1995, by a 3–2 vote, the CPUC adopted a compromise between the two competing plans. By 1998, a free market in electricity with direct access to suppliers for large customers will be established. There will be a five-year transition period, so that by 2003 all customers will be able to buy power from a supplier of their choosing. Also beginning in 1998, a power pool will be established, providing smaller companies with "virtual direct access." The pool will buy power from lowest-cost producers and resell to the state's utilities. Out-of-state and independent power producers can compete with California utilities to sell power to the pool. An Independent System Operator will run the transmission system of the investor-owned utilities. The CPUC order provides for recovery of transition costs by utilities. These costs include stranded assets and long-term contracts for power purchases from independent power producers at higher-than-market rates. The order calls for divestiture of up to 50% of the utilities' generating assets to ensure favorable stranded cost treatment. (The order is vague on how transition costs will be recovered.) [62,63]

Nuclear Power

Nuclear power plants in the United States improved their operating performance by several measures, continuing a trend of recent years. However, construction was terminated on several projects. The Energy Information Agency forecast declining production of electric energy from nuclear power plants in the future.

Slow progress on both permanent disposal and interim storage of spent nuclear fuel continued to be a major concern.

Power Plant Operations

In 1995, there were 109 operable commercial nuclear power units with full-power licenses issued by the U.S. Nuclear Regulatory Commission, with a total net capacity of 99,394 MWe. Together, these plants produced 673.4 TWh (net) of electric energy (up 5.2% from 640.4 TWh in 1994) for an average capacity factor of 77.5% (up from 73.8% in 1994). Nuclear energy accounted for 22.5% of the total electric energy generated by utilities in 1995 (up from 22.0% in 1994). Electrical generation from nuclear power is shown in Table 4. According to the Department of Energy, this increase is largely attributable to improved performance.[64]

Worldwide, in 1995, 437 nuclear power reactors generated 2,228 TWh of electricity, accounting for 17% of the world's electricity supply. Four reactors with a total capacity of 3,290 MWe came on line in India, South Korea, the United Kingdom, and Ukraine. Two plants, in Germany and Canada, ceased operation. Countries deriving a high percentage of their electricity from nuclear power in 1995 were France (76.1%), Belgium (55.5%), Sweden (46.6%), Bulgaria (46.4%), Switzerland (39.9%), Ukraine (37.8%), South Korea (36.1%), Spain (34.1%), Japan (33.4%), Germany (29.1%), Taiwan (28.8%), and the United Kingdom (25.0%).[65]

The Institute of Nuclear Power Operations reported improvements in reactor performance from 1994 to 1995 as follows: reduced collective radiation exposure to workers and volumes of solid low-level radioactive waste generated and increased thermal

Table 4. U.S. electrical generation from nuclear power.

	Year				
	1991	**1992**	**1993**	**1994**	**1995**
Total utility electrical generation (billion kWh)	2825	2797	2883	2911	2995
Nuclear contribution (billion kWh)	613	619	610	640	673
Percent nuclear	21.7	22.1	21.1	22.0	22.5
Installed nuclear capacity[a] (GWe)	99.6	99.0	99.0	99.1	99.1
Number of operable reactors	111	109	109	109	109
Annual nuclear capacity factor (%)	70.2	70.9	70.5	73.8	77.5

Source: *Monthly Energy Review*, DOE/EIA-0035(96/07) U.S. Department of Energy, Washington DC, (July 1996) Section 8.
[a]Net summer capability of operable reactors.

efficiency, fuel reliability, system safety performance (measure of availability of three important safety systems), and capacity factor.[66] As an example of improved operating performance, Southern California Edison Company's San Onofre Nuclear Generating Station (SONGS) Unit-2 set a world record for a continuous run by a large lightwater reactor. Until the reactor went off line for refueling in February, it had operated for 552 days and generated 14 billion kWh of electric energy. SONGS Units 2 and 3 set a record for a continuous run by a dual unit of 315 days. Another record was established by Pacific Gas & Electric Company's Diablo Canyon-2. The plant's refueling outage lasted only 34 days and 10 hours, a record for large, four-loop Westinghouse pressurized water reactors, and was accomplished at $10 million below budget.[67]

The last commercial nuclear power plant under construction in the United States, the Tennessee Valley Authority's (TVA) Watts Bar-1, a 1,177-MWe pressurized water reactor, completed hot functional testing at the end of August 1995 and received a low-power operating license from the U.S. Nuclear Regulatory Commission on November 9, 1995.[68] (The construction permit was granted in 1972.)

However, also during 1995, TVA canceled plans to finish Bellefonte Station Units 1 and 2 (88% and 57% complete) and Watts Bar Unit 2 (61% complete). The Washington Public Power Supply System (WPPSS) announced plans to begin demolition of its two partially completed nuclear plants WNP-1 and -3 at Richland and Satsop, Washington.[69]

Portland General Electric submitted to the U.S. Nuclear Regulatory Commission (NRC) its decommissioning plan for Oregon's Trojan plant. The Sacramento Municipal Utility District's decommissioning plan for its Rancho Seco plant was approved by NRC.[70]

The Energy Information Agency projected a decline in U.S. nuclear generating capacity from 99.0 GWe in 1993 to between 90.7 and 94.7 GWe by 2010. Since this projection was made by EIA, further cancellations of reactors by the Tennessee Valley Authority and the Washington Public Power Supply System will reduce nuclear capacity by another 5.0 MWe.[71]

High-Level Nuclear Waste

In 1995, the U.S. nuclear industry assigned a high priority to progress on the management and disposal of spent nuclear fuel (SNF) including development of an interim storage facility. Emphasis was placed on the following: ensuring adequate funding for the government's high-level waste (HLW) disposal program, establishing the U.S. Department of Energy's obligation to accept SNF beginning in 1998, development of a DOE capability for interim storage of SNF from 1998 to 2010 when a permanent disposal facility is expected to be ready, and continued progress in the development of a multipurpose canister system.[72]

On January 5, 1995, Senator Bennett Johnston (D-Louisiana), ranking minority member of the U.S. Senate Energy and Natural Resources Committee, introduced the Nuclear Waste Policy Act of 1995. The bill would provide for construction of an interim storage facility at the Yucca Mountain site in Nevada, which is being investigated by DOE as a permanent geologic repository for SNF and HLW. (Existing law—the 1987 amendments to the Nuclear Waste Policy Act—prohibits siting both an interim storage facility and a permanent repository in the same state.) The bill also provides that DOE must begin to accept SNF for storage by 2004. (Existing law requires the DOE to take title to SNF in 1998.)[73]

A bill supported by the nuclear industry, H.R. 1020, was introduced in the House on February 22, 1995, by Representatives Fred Upton (R-Michigan) and Edolphus Towns (D-New York). The Integrated Spent Nuclear Fuel Management Act of 1995 would provide for establishment of an interim SNF storage facility at the Nevada Test Site and require that DOE begin managing spent fuel by January 1, 1998. H.R. 1020 was approved by the House Commerce Committee on August 2, 1995, on a bipartisan vote of 30-4. The bill would change the funding mechanism for the government's HLW program. Currently, ratepayers pay one mill per kilowatt-hour. Under the provisions of H.R. 1020, ratepayers would pay only an amount equal to what the government spends in a given year.[74]

A Senate version of the HLW bill, S. 1271, was introduced on September 25, 1995, by Senator Larry Craig of Idaho. The Senate bill would provide for interim storage of as much as 120,000 metric tons of uranium (MTU) near Yucca Mountain in Nevada, twice as much SNF as the House bill. The bill would prohibit the Environmental Protection Agency from setting performance standards for the permanent repository.[75]

As of the end of 1995, neither S. 1271 or H.R. 1020 had come to a floor vote.[76]

A consortium of electric utilities, led by Northern States Power Co., continued their efforts to develop a privately funded SNF storage facility in cooperation with the Mescalero Apache Tribe on tribal land. In December 1994, the Tribal Council and a consortium of 32 utilities had announced a tentative agreement on a letter of intent to develop an SNF storage facility on the Mescalero Apache reservation. However, on January 31, 1995, a tribal referendum voted 490 to 362 against the project. This was reversed in a second referendum on March 9, 1995, by a vote of 593 to 372, allowing the Tribal Council to hold discussions with the electric utilities. Subsequently, 23 nuclear utilities led by Northern States Power Company and representing 75 of the country's 109 reactors, signed an agreement to support development of a SNF storage facility on Mescalero Apache land in New Mexico; and the utilities pledged funding for planning, engineering, design, and preparation of the license application. The facility would be designed to hold 20,000 metric tons of SNF for 20 years and could be upgraded to 40,000 for 40 years. The license application was scheduled to be filed in early 1996 and the facility in operation by 2002.[77]

Litigation filed in June 1994 by 14 utilities continued relative to DOE's responsibility to accept SNF beginning in 1998. In a notice published in the Federal Register on April 28, 1995, the DOE's Office of Civilian Radioactive Waste Management took the position that, under provisions of the Nuclear Waste Policy Act, it has no legal obligation to accept HLW and SNF in 1998 in the absence of an operational repository.[78] DOE's position was criticized by representatives of the nuclear industry and by some members of Congress.

Carbon Emissions and Energy Use

Increasing emission of greenhouse gases (carbon dioxide, methane, nitrous oxide, and others) may increase the Earth's temperature and affect climate. U.S. carbon emissions from energy use are projected to increase on the average of 1.2% per year from 1995 to 2015, reaching 1,799 million metric tons. Per capita emissions are projected to grow by only 0.3% a year.[79] The 1994 *Climate Change Action Plan* (CCAP) developed by the Clinton Administration to stabilize U.S. greenhouse gas emissions by the year 2000 at 1990 levels may be ambitious, especially since emissions in the 1990s have grown more rapidly than projected at the time the plan was formulated.[80] Emissions from fuel combustion (largely from combustion of coal, natural gas, and petroleum), the primary source of carbon emissions, were about 1,340 million metric tons in 1990. Carbon emissions reported for 1995 were 1444.5 million metric tons.[81]

Petroleum products were the leading source of carbon emissions from energy use in 1995. In 2015, petroleum is projected to contribute 747 million metric tons of carbon to the total 1,799 million tons.[82] Approximately 80% (587 million metric tons) of petroleum emissions result from transportation use. This could be lower with less travel or with faster development and use of higher efficiency or alternative-fuel vehicles. The second leading source of carbon emissions is coal. It is projected that the use of coal will produce 607 million metric tons in 2015, or 34% of the total. Most of the coal emissions result from electricity generation. Natural gas is projected to produce 444 million metric tons of carbon emissions, a 25% share, in 2015. Although natural gas consumption and emissions are projected to increase most rapidly through 2015 at an average rate of 1.7% annually, natural gas produces only about half the carbon emissions of coal per unit input.[83] The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Between 1995 and 2015, it is expected that there will be a 33% decline in nuclear power generation; 38 GW of nuclear capacity are expected to be retired.[83] It is projected that 294 GW of new fossil-fueled capacity (excluding cogeneration) will be needed to compensate for this loss of baseload capacity and to meet a rising demand. Increased fossil fuel use will increase carbon emissions by 172 million metric tons, or 34% above 1995 levels. Renewables are not expected to completely compensate for this loss of capacity because of their intermittent nature.[83]

Appendix

Data and Conventions Used in Construction of Energy Flow Charts

Data for the flow charts were provided by tables in the Department of Energy's *Annual Energy Review—1996,* the *Renewable Energy Annual—1996,* and the *Monthly Energy Review* (Dec. 1997).

The residential and commercial sector consists of housing units, nonmanufacturing business establishments, health and educational institutions, and government office buildings. The industrial sector is made up of construction, manufacturing, agriculture, and mining establishments. The transportation sector combines private and public passenger and freight transportation, including military operations.

Utility electricity generation includes power sold by both privately and publicly owned companies. The nonfuel category of end use consists of fuels that are not burned to produce heat, e.g., asphalt, coal oil, petrochemical feedstocks such as ethane, liquid petroleum gases, lubricants, petroleum coke, waxes, carbon black, and crude tar. Coking coal traditionally is not included.

The conversion and plant losses associated with utility electrical power generation are a matter of record. Transmission losses are the difference between total transmitted electricity and receipts by the principal end-use sectors. They are estimated to be 9% of the gross generation of electricity by utilities. In other sectors, such as residential/commercial, industrial, and transportation, the division between "useful" and "rejected" energy is arbitrary and depends on assumed efficiencies of conversion processes. In the residential and commercial end-use sectors, a 75% efficiency is assumed, which is a weighted average between space heating at approximately 60% and electrical motors and other electrical uses at about 90%. Eighty percent efficiency is assumed in the industrial end-use sector and a generous 20% in transportation. This is below the 25% efficiency we have used in past years. The latter percent corresponds to the approximate efficiency of the internal combustion engine as measured on the bench by "brake thermal efficiency" tests.

We have persisted in expressing these approximate efficiencies in our flow charts over the years, although we are fully aware of the changes in all end-use sectors that have modified actual efficiencies to some degree over the same time period. Unfortunately we lack quantitative data to improve our estimates. We feel, however, that despite improved mileage for highway vehicles, it is unlikely that transportation efficiencies in reality have reached 20% and certainly not the 25% associated with bench tests. In other end-use sectors, not only have some efficiencies changed but also the slate of fuels used by the various end-use sectors has changed, which influences the average efficiency for the sector. For example, electrical usage has steadily risen in the residential and commercial sectors because of increased use of air conditioners; natural gas has a bigger share of the heating market than in the past. We are uncertain of the net result of these changes. Another uncertainty has to do with the influence of cogeneration and self-generation of electrical power on overall industrial efficiencies. Clearly the magnitude of the effect relates to the waste heat associated with nonutility electric generation that is used in other industrial processes. Rather than abandon the approach because of uncertainties, we continue to estimate "rejected" and "useful" energy in order to point out which of the various energy sectors are associated with the largest absolute losses, such as electrical power production and transportation, and thus to direct attention to the most fertile ground for technological improvements.

There are some minor differences between the total energy consumption shown in the energy flow chart (Fig. 1) and the DOE/EIA totals given in Table 1. The industrial consumption total in Table 1 agrees with DOE's *net* industrial total. Both totals include natural gas lease and plant fuels and nonfuel ("nonenergy") use, which are shown separately in the flow chart.

Finally, in past years the energy flow charts were prepared using preliminary data from DOE/EIA's *Monthly Energy Review*, allowing an early release of the reports in this series. Because of the timing of this 1995 report, biofuel consumption data not fully reported in DOE/EIA's monthly publication was available from DOE/EIA's *Annual Energy Review* and *Renewable Energy Annual* publications, allowing our calculated energy consumption to closely compare to that reported by DOE/EIA.

Conversion Factors

The energy content of fuels varies depending on source, fuel type, and year. Some conversion factors, useful for estimation, are given below.

Fuel	Energy content (Btu)
Short ton of coal	21,400,000
Barrel (42 gallons) of crude oil	5,800,000
Cubic foot of natural gas	1,027
Kilowatt hour of electricity	3,412

More detailed conversion factors can be found DOE/EIA's *Annual Energy Review* or *Monthly Energy Review*.

References

1. *Annual Energy Review—1996*, DOE/EIA–0384 (97), U.S. Dept. of Energy, Washington, DC (July 1997) Tables 1.2, 1.4, 1.16, 2.1, 5.1, 5.14, 6.1, 6.3, 6.6, 7.1, 7.5, 8.3, 8.5, and 10.2.

2. *Monthly Energy Review*, DOE/EIA–0035 (97/12), U.S. Dept. of Energy, Washington, DC (Dec. 1997) Table 2.5.

3. *Renewable Energy Annual —1996*, DOE/EIA–0603 (96), U.S. Dept. of Energy, Washington, DC (Mar. 1997) Tables 1–4.

4. *Annual Energy Outlook —1997*, DOE/EIA–0383 (97), U.S. Dept. of Energy Washington, DC (Dec. 1996) Table B8.

5. *California Economic Indicators*, Department of Finance, Sacramento, CA (Nov./Dec. 1995) p. 3.

6. *Annual Energy Review —1996*, Table 5.1.

7. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves —1995,* Annual Report, DOE/EIA–0216 (95), U.S. Dept. of Energy, Washington, DC (Nov. 1996) Section 2 and Table 1.

8. "Showdown near for ANWR leasing issue," *Oil and Gas Journal* (Nov. 6, 1995) p. 31.

9. *Annual Energy Outlook —1997*, p. 8

10. "Clinton ends export ban on North Slope crude," *Oil and Gas Journal* (May 6, 1996) p. 52.

11. *Annual Energy Review—1995*, DOE/EIA–0384 (96), U.S. Dept. of Energy, Washington, DC (July 1996), p. 138.

12. *Annual Energy Review —1996*, Table 5.3.

13. *Monthly Energy Review*, DOE/EIA-0035 (97/12), U.S. Dept. of Energy, Washington, DC (Dec. 1997), Table 3.3.

14. *Fuel Oil and Kerosene Sales—1995*, DOE/EIA–0535 (95), U.S. Dept. of Energy, Washington, DC (Sept. 1996) p. 3.

15. *Fuel Oil and Kerosene Sales —1995*, p. 7.

16. *Fuel Oil and Kerosene Sales —1995*, p. 11.

17. *Fuel Oil and Kerosene Sales —1995*, p. 12.

18. *Petroleum Marketing Annual —1995*, DOE/EIA–0487 (95), U.S. Dept. of Energy, Washington, DC (1996).

19. *Annual Energy Review —1996*, Table 5.20.

20. *Annual Energy Outlook —1997*, p. 21.

21. *Annual Energy Outlook —1997*, p. 44.

22. *Annual Energy Review —1996*, Table 6.2.

23. *Natural Gas Annual—1995*, DOE/EIA–0131 (95), U.S. Dept. of Energy, Washington, DC (Nov. 1996) p. 1, 2.

24. *Annual Energy Review —1996*, Table 6.1.

25. *Annual Energy Review —1996*, p. 182.

26. *Natural Gas Annual —1995*, p. 9.

27. *Natural Gas Annual —1995*, pp. 19–21.

28. *Natural Gas Annual —1995*, p. 10.

29. *Annual Energy Review —1996*, p. 181 and Table 6.7.

30. *Natural Gas Annual —1995*, p. 2.

31. *Natural Gas Annual —1995*, p. 35.

32. *Annual Energy Review —1996*, Table 6.9.

33. *Natural Gas Annual —1995*, p. 36.

34. *Annual Energy Review —1996*, Table 6.6.

35. *Coal Industry Annual —1995*, DOE/EIA–0584 (95), U.S. Dept. of Energy, Washington, DC (Oct. 1996) p. 1.

36. *Annual Energy Review —1996*, Table 7.3.

37. *Coal Industry Annual —1995*, p. 129.

38. *Annual Energy Review —1996*, Table 7.7.

39. *Coal Industry Annual —1995*, p. 151.

40. *Renewable Energy Annual—1996*, Tables 1–4.

41. *Renewable Energy Annual —1996*, p. 9.

42. *Annual Energy Review —1996*, p. 261.

43. *Renewable Energy Annual—1996*, Tables 1–4 and pp. 9–11.

44. *Electric Power Annual —1995*, Vol. 2, DOE/EIA–0348 (95)/2, U.S. Dept. of Energy, Washington, DC (Dec. 1996) Table 1.

45. *Renewable Energy Annual —1996*, p. 10.

46. *Annual Energy Outlook — 1996*, DOE/EIA–0383 (96) U.S. Dept. of Energy, Washington, DC (Jan. 1996) p. 36.

47. *Annual Energy Outlook —1997*, p. 56.

48. *Annual Energy Review —1996*, Table 8.12.

49. *Renewable Energy Annual —1996*, p. 51.

50. *Electric Power Annual —1995*, Vol. 2, Table 1.

51. *Electric Power Annual—1995*, p. 6.

52. *Annual Energy Review—1996,* Table 8.3.

53. *Annual Energy Outlook —1997*, p. 74.

54. *Inventory of Power Plants in the United States—1996*, DOE/EIA–0095 (96) U.S. Dept. of Energy, Washington, DC (Dec. 1996) p. 4.

55. *Inventory of Power Plants in the United States—1996*, p. 3.

56. *Inventory of Power Plants in the United States—1995*, Office of Coal, Nuclear, Electricity and Alternate Fuels, Energy Information Administration, U.S. Dept. of Energy, Washington, DC (Jan. 1997).

57. Linda G. Stuntz, "Current Shock: Competition in Electricity Service," *Resources*, Winter 1995 (published for Resources for the Future).

58. Agis Salpukas, "Pulling the Plug on the Utilities," *New York Times*, May 18, 1995.

59. David Field, "Surge in utility mergers sparks massive restructuring," *The Washington Times*, Sept. 10, 1995.

60. Agis Salpukas, "A U.S. Order Opens Power Cost and Supply to Competition," *New York Times*, March 30, 1995.

61. Benjamin Holden, "California's Struggle Shows How Hard it is to Deregulate Utilities," *Wall Street Journal*, Nov. 28, 1995.

62. Agis Salpukas, "California to Get Choice on Utilities," *New York Times*, Dec. 21, 1995.

63. Benjamin A. Holden, "California Regulators Approve Plan to Deregulate Market for Power by '98," *Wall Street Journal*, Dec. 21, 1995.

64. *Nuclear Power Generation and Fuel Cycle Report—1996,* DOE/EIA–0436 (96), Oct. 1996, Energy Information Administration, U.S. Dept. of Energy, Washington, DC, pp. 2, 5.

65. "First reprocessing waste returned amid protests," *Nuclear News,* **39,** No. 7 (June 1996) p. 36.

66. "Nuclear industry continues improvement," *Nuclear News,* **39,** No. 6 (May 1996) p. 20.

67. "Late news in brief," *Nuclear News,* **38**, No. 3 (Mar. 1995); "Video helmet makes quick and effective maintenance a virtual reality," **38,** No. 5 (Apr. 1995) p. 28.

68. "Plan completes HFT, but can TVA compete?" *Nuclear News,* **38,** No. 13 (Oct. 1995) p. 21; "Late news in brief," **38,** No. 15 (Dec. 1995) p. 13; **39, No. 2** (Feb. 1996).

69. "NRC confidence depends on TVA Results," *Nuclear News,* **38,** No. 3 (Jan. 1995), p. 29; "Two partially finished plants pass into oblivion," **38,** No. 3 (March 1995), p. 21.

70. "PG&E submits decom plan, begins component removal," *Nuclear News,* **38,** No. 3 (Mar. 1995) p. 20; "Power briefs," **38,** No. 7 (May 1995) p. 21.

71. "Power Briefs," *Nuclear News,* **38,** No. 2 (Feb. 1995) p. 26.

72. "Reports: Strategic Plan: Focus on performance, waste," *Nuclear News,* **38,** No. 1 (Jan. 1995) p. 30.

73. "Johnston bill seeks storage at Yucca Mountain," *Nuclear News,* **38,** No. 2 (Feb. 1995) p. 55.

74. "Bills on HLW introduced; Senate committee hearing," *Nuclear News,* **38,** No. 5 (Apr. 1995) p. 38.

75. "Craig introduces reform legislation in Senate," *Nuclear News,* **38,** No. 14, (Nov. 1995) p. 49.

76. "Late News: '1995 was a take-charge year'," *Nuclear News*, **39,** No. 2 (Feb. 1996) p. 18.

77. "Mescaleros utility pact on private MRS moves ahead," *Nuclear News,* **38,** No. 2 (Feb. 1995) p. 39; "Mescaleros vote no on interim repository," **38**, No. 3 (March 1995) p.25; "Tribe, utilities incorporate; agreement, contracts," **39**, No. 4 (Apr. 1996) p. 44; "Innovation, cost effectiveness, technical excellence," **39**, No. 1 (Jan. 1996) p. 19.

78. *Nuclear News,* June 1995, p. 55.

79. *Annual Energy Outlook —1997,* DOE/EIA, 0383 (97), Dept. of Energy, p. 72.

80. Clinton, W.J. and Gore, A. *The President's Climate Change Action Plan,* Washington, DC, October, 1994. Available through U.S. Dept. of Energy, Office of Public Information. Also available on the Internet at http://gcrio.org/USCCAP/toc.html.

81. *Emissions of Greenhouse Gases in the United States —1996*, DOE/EIA–0573 (96), Department of Energy, Washington, DC (Oct. 1997) p. 13.

82. *Annual Energy Outlook —1997*, pp. 72–73.

83. *Annual Energy Outlook —1997,* DOE/EIA, 0383 (97), Dept. of Energy, p. 73.